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RSCAS 2013/46
Robert Schuman Centre for Advanced Studies
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EUI Working Paper **RSCAS** 2013/46

ISSN 1028-3625



Printed in Italy, June 2013
European University Institute
Badia Fiesolana
I – 50014 San Domenico di Fiesole (FI)
Italy
www.eui.eu/RSCAS/Publications/
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# Incentive or impediment? The impact of capacity mechanisms on storage plants

Katrin Schmitz*, Bjarne Steffen, Christoph Weber.

April 28, 2013

**Abstract**

Capacity remuneration mechanisms are a widespread instrument to foster investment. The growing interest in electricity storage raises the question how these mechanisms interact with storage plants. Using a stylized capacity planning model, we demonstrate that an exclusion of storage plants from capacity mechanisms leads to welfare losses. Even if storages are not explicitly excluded, the setup of capacity mechanisms can discriminate storage implicitly—we therefore discuss typical mechanism design parameters and their impact on storage plants. Three case studies describe the actual situation of storage plants in the PJM system, Ireland and Spain. Finally the findings are summarized to general principles for storage-compatible capacity mechanisms.

Keywords: capacity market, pumped-hydro storage, power plant investment

JEL classification: L51, L52, L94, Q41, Q42, Q48

## 1 Introduction

Being the most prevalent form of energy, a reliable supply of electricity is of utmost importance for industrialized economies. A prerequisite for this is an adequate generation park, able to meet the load at any point in time. In many European countries, large thermal units will soon be decommissioned due to their highly polluting emissions, and the large-scale integration of wind and solar power requires increasingly flexible plants as a complement. Consequently, new power plants have to be constructed, especially in countries that also decided to phase-out their nuclear fleet following the Fukushima incident. Some markets (e.g., Germany) are still characterized by overcapacities that serve as a buffer, but generation adequacy might well become an area of concern in the medium term.

In liberalized electricity markets, the available plant park is the result of investment decisions made by individual market participants. As economic theory shows, the aggregate of individual investments yields a socially efficient plant park under certain conditions—most importantly, wholesale prices have to serve as efficient signals (cf. e.g., Joskow and Tirole 2007). In reality, though, electricity prices are capped or distorted and do not necessarily cover the capital costs of power plants. Therefore, among other reasons, many countries do not rely on 'energy only' markets but have implemented capacity

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remuneration mechanisms in order to ensure an adequate amount of available generation capacity.

To date, capacity mechanisms primarily address thermal generation technologies, especially those that are characterized by comparably low investment costs and short start-up times. Apart from maintenance outages, thermal plants are generally available, resulting in a high capacity credit. In contrast, the availability of electricity storage plants is limited by the amount of stored energy in the reservoirs—a drawback compared to thermal plants. In the light of ambitious targets to reduce carbon emissions of power generation, though, storage plants are increasingly considered as an alternative way to secure generation adequacy, despite their operating restrictions and higher capital costs. The most important technology is pumped-hydro storage, with 95 GW installed capacity worldwide and several GW being under construction (Deane *et al.*, 2010). Pumped-hydro storage plants are likely to grow in importance especially in systems where the feed-in from fluctuating renewable energy sources exceeds the load in certain moments: In those cases, storage capacities add to an efficient power system both by $CO_2$-free electricity generation in situations with low wind and solar power, and by absorbing the excess generation in times of high wind/solar radiation and low load.

As the development of pumped-hydro storage plants re-gains momentum, it is of great importance how capacity mechanisms address the specific characteristics of storage plants: Capacity payments might contribute significantly to cover the high capital costs that are typical for pumped-hydro plants, creating an incentive to extent storage capacity. At the same time, capacity mechanisms are complex market interventions with the potential to distort the cost position of different generation technologies, which might ultimately impede investments into 'discriminated' technologies. At the time of writing this article, capacity mechanism regulation is in flux in many European markets (e.g., France, Germany, UK), resulting in significant uncertainty concerning the impact on storage investments. The situation in Germany serves as an example: Relying historically on an 'energy only' setup, the introduction of a capacity remuneration mechanism is vigorously discussed, while more than 4 GW new pumped-hydro storage plants are planned but investment decisions are pending (Steffen 2012). The present article shows that the design of capacity mechanisms can have a significant impact on storage investment decisions and overall power system efficiency—which is why we argue that these effects have to be taken into account carefully in order to design capacity mechanisms that do not distort the cost-efficient generation mix.

Based on the variety of capacity mechanisms implemented in different countries, numerous articles present possible setups of capacity mechanisms and discuss the appropriateness of design parameters (e.g., Joskow 2008, Battle and Rodilla 2010, Cramton and Ockenfels 2012). To our knowledge, however, the specific situation of storage plants has not yet been addressed in detail. Ruester *et al.* (2012), Sioshansi *et al.* (2012) and Steffen (2012) discuss the general regulatory environment for storage plants in Europe and the U.S., but do not specifically address the consequences of capacity mechanisms. This is where we add to the literature.

The next section starts with a brief discussion of the rationale for capacity mechanisms. In section 3, a stylized numerical model is used to demonstrate the welfare effects of capacity mechanisms that exclude storage plants or not. An assessment of typical design parameters in section 4 underlines that depending on the specific design of capacity mechanisms, storage plants are possibly 'discriminated' in a way that they are no longer considered as investment alternative. Three case studies illustrate the current situation for storage plants in the U.S. East Coast PJM system, Ireland and Spain. Finally, section 5 summarizes general principles for storage-compatible capacity mechanisms and concludes.

## 2 Market efficiency and capacity mechanisms

The design of electricity wholesale markets has to target not only the efficient dispatch in the short run, but also to motivate necessary investments. Many authors have shown that in theory, energy spot markets are able to provide cost-covering rents for the efficient portfolio of generation technologies and adequate price signals for investments (cf. e.g., Joskow and Tirole 2007, Schweppe *et al.* 1982, Stoft 2002). This holds as long as prices rise to a scarcity level (reflecting the value of lost load VOLL) when the load exceeds the available capacity (cf. Joskow 2008, de Vries 2004). But if capacity is adequate, spot prices are too low to motivate investments in new generation capacity (cf. Cramton and Ockenfels 2012). Assuming perfect competition, power plants bid into the market with their marginal production costs as their investment costs are already sunk. Following the merit order, prices are set by the marginal production costs of the last power plant needed to satisfy demand. While at peak times base load plants earn rents above their own marginal production costs (namely in the amount of the marginal production costs of the peak load technology), the marginal peak load plant earns just its marginal production costs and has therefore no possibility to cover its investment costs. In competitive markets, capacity has no positive value unless capacity is scarce (cf. Cramton and Ockenfels 2012).

There are further reasons why 'energy only' markets might not lead to efficient solutions. Electricity demand is typically not flexible enough to respond adequately and there is a time gap between capacity investment decisions and commissioning, which could make market clearing impossible in situations of scarcity. Especially in periods of scarcity a few 'remaining' suppliers might have substantial market power. Moreover, spiking prices could be considered as unacceptable by the public and regulators, which turns it unlikely that investments are made relying on the occurrence of scarcity prices in the future. In sum, additional reliable revenues might be required to ensure generation.

Coming from the (more technical) reliability perspective, energy spot markets should set adequate incentives to ensure an efficient security of supply level (cf. e.g., Hogan 2005, Joskow 2008 an Finon *et al.* 2008). Nowadays the question of security of supply is increasingly becoming a focus of economic and political debate. Especially in RES-dominated energy systems, investors have to be found to build power plants only running in those hours in which sun and/or wind are low.[1] But to make such investments attractive to investors the market has to set the right price signals. During scarcity conditions spot prices have to be high enough to provide cost-covering rents. Hogan (2005) argues that the 'missing money' problem results mainly from price caps as those prevent prices from reaching cost-covering price levels (for new power plants) within scarcity periods. But highly volatile prices, rising up in scarcity hours very high seem to be 'politically not feasible'. He demonstrates that the missing investment incentives could also be set through a re-configuration of 'energy-only' markets: "The main innovations of the energy-only market design would be in the configuration of the reserve demand curves, connection to the average VOLL, and elimination of de facto price caps" (Hogan, 2005, p. 6). As he argues, regulatory interventions would still be needed (e.g., to prevent the exercise of market power) but their character would be substantially changed. One the one hand, short-term security could be sufficiently ensured by operation reserves markets where the system operator describes the reserve requirements. On the other hand, reserve markets cannot solve the question for strategic expansion policy as Battle and Rodilla (2010) term the not security-related dimension of the 'missing money' problem. Strategic expansion policy means for them a very long-term dimension including the diversification of fuel and the technology mix of generation which can only be addressed by the implementation of specific capacity mechanisms (e.g., administrative capacity payments or a trade

[1] Statistically, wind and sun energy production compensate each other to a certain extent especially with a suitable large geographical scope.

mechanism).[2]

While so far we referred to capacity mechanisms in general, very different setups have been implemented in practice, resulting in varying degrees of market intervention. The impact of different setups on storage plants is discussed in the following, starting with a stylized modeling of the most important apparent question: Inclusion or exclusion of storage plants from capacity payments.

# 3 Capacity payments, cost coverage and welfare effects

The motivation for capacity mechanisms and their impact on storage plants can be illustrated consistently by means of a numerical example. This approach is inspired by Joskow (2008) who discusses the 'missing money' problem of an efficient thermal plant park derived through peak-load-pricing theory. The classical peak-load-pricing model has been extended by Steffen and Weber (2013) to include storage plants; in this section we apply their model to discuss textbook case capacity mechanisms. Explaining the intuition of the model (for a formal treatment, the reader is referred to Steffen and Weber 2013), we proceed in three steps: First, the long-term efficient portfolio of generic generation technologies (including storage) is derived. Second, cost coverage in 'energy only' markets with and without price caps is analyzed, following the approach of Joskow (2008), but including storage. Third, we go a step further by considering two generic capacity payment schemes and deriving their implications for storage investments as well as total system costs.

## 3.1 Efficient generation portfolio

As the adequacy of available generation capacity depends on power plant investment decisions, a long-term perspective is required. We therefore start with the derivation of the long-term efficient generation portfolio from a system point of view, abstracting from any legacy plants. While the calculations are illustrative, we use load data from Germany, a liberalized market in which the introduction of a capacity mechanism is vigorously discussed and new pumped-storage plants have been proposed.[3]

The chronological load curve for a typical week in 2011 is shown in figure 1a. Given the instantaneous feed-in of wind and solar power, we subtract their generation from the total load, leading to the residual load that has to be met by controllable plants. The chronological residual load curve exhibits the current weekly pattern in Germany where storage plants are usually operated in day-night cycles on weekdays but not on weekends (leading to approximately 260 cycles per year). Re-arranging the hours by magnitude yields the residual load duration curve (LDC) that is the basis for the subsequent discussion (figure 1b). To simplify matters, we ignore uncertainty and take the curve as given.

To meet the residual load, three generic technologies are considered: A controllable base technology (one could think of coal-fired plants), a generic peak technology (e.g., gas-fired plants) and a storage technology (e.g., pumped-hydro storage). All technologies are characterized by linear fixed and variable costs as described in table 1. The storage technology converts energy with a round-trip efficiency of 80%, costs occur both for turbines/pumps and the reservoir. While the demand is generally assumed to be inelastic, we allow the load to be reduced in super-peak hours at very high costs that occur to disconnected customers (a.k.a. the VOLL).[4]

[2]See Stoft (2002) for a differentiation of reserve and capacity markets

[3]Hourly total load values provided by ENTSO-E; hourly wind and solar feed-in values based on statutory publications from 50Hertz Transmission GmbH, Amprion GmbH, TransnetBW GmbH and TenneT TSO GmbH.

[4]For the illustrative purpose of the calculation, demand reduction costs are also assumed to be linear.

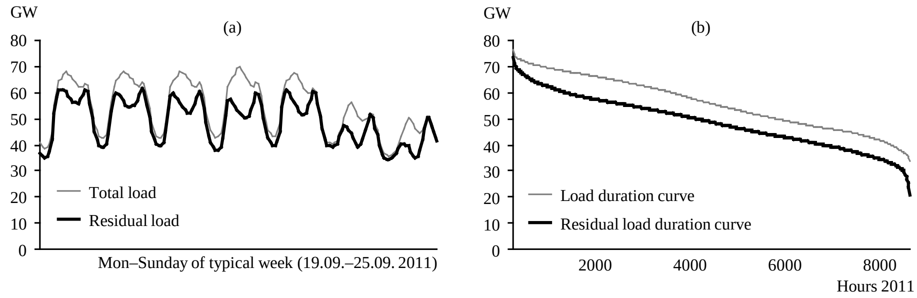


Figure 1: Load and load duration curves for Germany

| | Fixed costs[a] | | Variable costs | Round-trip efficiency |
|---|---|---|---|---|
| | €/$MW$ | €/$MWh$[b] | €/$MWh$ | $kWh_{out}/kWh_{in}$ |
| Base | 150,000 | | 30 | |
| Storage | 80,000 | 5,000 | – | 80% |
| Peak | 50,000 | | 100 | |
| Demand reduction | 0 | | 3,000 | |

[a] Annualized
[b] Reservoir size dependent costs

Table 1: Technical parameters of stylized technology portfolio

Given the LDC and the technology characteristics, the efficient generation portfolio follows from a cost trade-off: There is an annual operating time from which on the base technology is most economic, as its low operating costs make up for its high fixed costs—in the present example, base plants are the cheapest solution for units that run at least 2619 hours a year (see table 2). Consequently, the value of the LDC at 2619 hours gives the efficient capacity of 54.90 GW base plants—part of this capacity will run 8760 hours a year, and another part has lower run times with 2619 hours being the minimum. The efficient capacity of the other technologies is derived along the same cost trade-offs between the respective merit-order neighbors. For the storage technology, operating costs are thereby driven by additional base-load generation that is used to fill-up the reservoir, round-trip losses and reservoir-size dependent costs (see Steffen and Weber (2013) for details).

The cost-efficient plant park for the given LDC is summarized in table 2. In this stylized system, the lion's share of total capacity is of base technology with 54.90 GW, alongside 7.88 GW of storage plants and 8.25 GW of peak units. In the 17 hours with the highest demand, it is most efficient to reduce the load from the demand side, so that up to 2.67 GW load are 'covered' by demand reductions.

## 3.2 Cost coverage and the 'missing money' problem

While the generation portfolio derived above is efficient from a system point of view, it does not necessarily follow that the portfolio is reached in liberalized power markets where the available plant park is a result of decentralized investment decisions. We therefore evaluate whether the earnings of plant operators in competitive power markets cover their costs, which would imply sufficient incentives to invest into capacities.

To start with, an ideal 'energy only' wholesale electricity market is looked at (Case A). Following merit-order based pricing, hourly electricity prices are set by the variable costs of the marginal technology, i.e. the cheapest technology that is not yet running at full capacity. As long as the load is less than or equal to the available base capacity of 54.90

| | Capacity *GW* | Reservoir *GWh* | Annual run time *h* | Total generation *GWh* | Total costs *€M* |
|---|---|---|---|---|---|
| Base | 54.90 | | 2619–8760 | 426,958[a] | 20,595 |
| Storage | 7.88 | 45.96[b] | 694–2618 | 11,949 | 1,309[c] |
| Peak | 8.25 | | 18–693 | 2,228 | 635 |
| Dem. red. | 2.67 | | 1–17 | 14 | 41 |

[a] Including 14,937 GWh base technology generation to fill-up the storage reservoir
[b] Annual storage cycles: 260
[c] Storage covers variable costs for base technology generation that is used to fill-up the reservoir

Table 2: Efficient energy system

GW, the base plant sets the price (6142 hours). For 1925 hours, the storage technology is marginal, and for 676 hours the electricity price rises to the variable costs of peak plants. In the 17 super-peak hours the generation system is already operated at full capacity and the electricity price jumps up to the value of lost load (i.e. demand reductions are required to ensure the balance of supply and demand). As there is a single electricity price for every hour, all technologies profit from the scarcity prices in these hours.

The earnings of each technology are compared with the respective total costs in table 3 (Case A). In line with the theory of efficient wholesale electricity markets (e.g., Joskow and Tirole 2007), all technologies are able to cover fixed and variable costs with the revenues from energy sales, hence the total cost-efficient generation portfolio is feasible in an ideal 'energy only' market.

In practice, though, electricity wholesale markets are typically not ideal. As pointed out in section 2, it might be the case that regulators do not allow energy prices to rise up to the efficient scarcity price level (€/MWh 3000 in our example). Case B in table 3 therefore exhibits the consequences for the case that energy prices are capped, which means that they are not allowed to rise above the variable costs of the peak technology (€/MWh 100). While this price cap is binding in only 17 hours, all technologies clearly fail to cover their costs. The smaller the number of annual run hours, the more a technology depends on the scarcity prices and is affected by the price cap looked: The shortfall of total costs is 13% for base plants, 30% for storage, 65% for peak plants and 95% for demand reduction measures. Energy prices are no longer sufficient to justify any investment into capacities, which is described as 'missing money' problem in the literature (see section 2). Hence, the price-capped 'energy only' market is clearly not a sustainable setup—which is the reason for policy makers to consider market interventions like capacity mechanisms that are discussed next.

| | Total costs | **A.** Pure 'energy only' market | | **B.** Price-capped 'energy only' market[a] | |
|---|---|---|---|---|---|
| | | Revenues | Shortfall | Revenues | Shortfall |
| | *€M* | *€M* | *€M* | *€M* | *€M* |
| Base | 20,595 | 20,595 | 0 | 17,849 | 2,747 |
| Storage | 1,309[b] | 1,309 | 0 | 914 | 394 |
| Peak | 635 | 636 | 0 | 223 | 413 |
| Dem. red. | 41 | 41 | 0 | 2 | 39 |

[a] Price capped at marginal costs of peak technology (€/MWh 100)
[b] Storage covers variable costs for base technology generation that is used to fill-up the reservoir
Note: Numbers might not add up due to rounding

Table 3: Revenues and cost coverage in 'energy only' markets

### 3.3 Generic capacity mechanisms

To analyze the effect of capacity mechanisms on cost coverage and the generation portfolio, we stick to the situation with a price-cap on electricity wholesale prices as described in Case B. If the price ceiling is equal to the variable costs of the peak technology, a simple capacity mechanism would be a payment in the magnitude of the fixed costs of peak plants (the cheapest plant technology in terms of fixed costs).

In table 4, the effects of two alternative designs of such capacity payments are shown. Case C assumes that all technologies qualify to receive a uniform capacity payment of €/MW 50,000.[5] The cost-efficient technology portfolio (after capacity payments) equals the portfolio in the 'energy only' market. Remarkably, also the size of the storage reservoir equals the solution in the case above. This contradicts a possible first impression that capacity payments (applying per MW turbine capacity, not per MWh reservoir size) could induce a storage setup with large turbines and very small reservoirs. However, the position of the storage plant in the merit order does not change and the relative cost position compared to the adjacent peak technology stays the same, thereby resulting in the same number of cycles (260 in this example) that are efficiently commercialized by the storage plant. It does not make a difference whether additional revenues for cost coverage stem from 17 hours with high scarcity prices or from capacity payments in the same magnitude.

Adding up merit-order based energy prices and capacity payments, all technologies are able to cover their costs. Cost coverage is evident for the peak plant as we assume capacity payments in the amount of its fixed costs. For storage and the base technology, the payment covers only part of the fixed costs; at the same time, their annual run time is longer and they can still earn part of their fixed costs by selling energy at the price set by the peak plant. In sum, the price-capped energy market with uniform capacity payments for all plant technologies (Case C) is a sustainable solution.

| | **C.** Price-capped energy market with capacity payments *including* storage | | | | | |
|---|---|---|---|---|---|---|
| | Capacity $GW$ | Reservoir $GWh$ | Total costs €$M$ | Revenues €$M$ | Cap. Payment €$M$ | Shortfall €$M$ |
| Base | 54.90 | | 20,595 | 17,849 | 2,745 | 0 |
| Storage | 7.88 | 45.96 | 1,309[a] | 914 | 394 | 0 |
| Peak | 8.25 | | 635 | 223 | 413 | 0 |
| Dem. red. | 2.67 | | 41 | -92[b] | 133 | 0 |

| | **D.** Price-capped energy market with capacity payments *excluding* storage | | | | | |
|---|---|---|---|---|---|---|
| | Capacity $GW$ | Reservoir $GWh$ | Total costs €$M$ | Revenues €$M$ | Cap. Payment €$M$ | Shortfall €$M$ |
| Base | 58.86 | | 21,426 | 18,483 | 2,943 | 0 |
| Storage | 0 | 0 | – | – | – | – |
| Peak | 12.17 | | 1,237 | 628 | 609 | 0 |
| Dem. red. | 2.67 | | 41 | -92[b] | 133 | 0 |

[a] Storage covers variable costs for base technology generation that is used to fill-up the reservoir

[b] Negative revenues occur as demand reductions at negative prices are offered to receive the capacity payment

Note: Price capped at marginal costs of peak technology (€/MWh 100), uniform capacity payments for all technologies, set according to fixed costs of peak technology (€/MW 50k). Numbers might not add up due to rounding

Table 4: Capacities, costs and revenues under two capacity mechanisms

As mentioned in the introduction, storage differs from other plant technologies by a fundamental operational restriction: Power generation is only possible if the reservoir

[5] In the case of demand reductions, the capacity payment can be interpreted as a payment per MW that is made to certain customers that agree to have their demand reduced in super-peak hours.

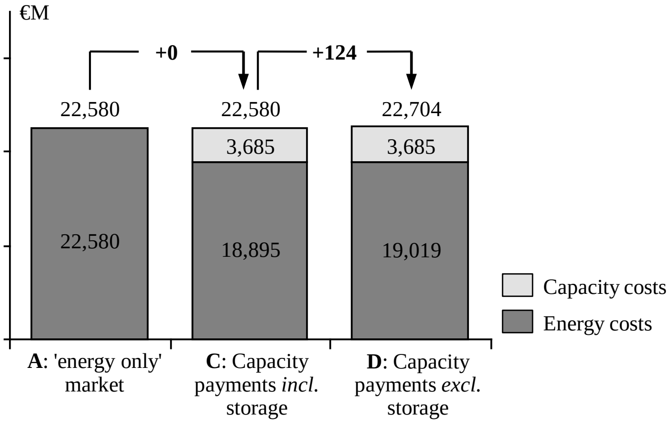


Figure 2: Total costs of 'energy only' market and capacity payment systems

fill-level allows it, e.g., if sufficient water is available in the upper basin of a pumped-hydro plant. Consequently, the qualification of storage plants for a capacity mechanism is not self-evident: On the one hand, regulators could decide to exclude storage plants de jure from payments if they are unable to meet some availability criterion. On the other hand, a variety of specific mechanism design parameters might discriminate storage plants compared to thermal units in a way that they are de facto excluded from capacity payments—which is discussed in detail in the next section. Within the scope of the numerical example, we therefore also analyze the case of capacity payments that are available to thermal technologies but not to storage; the situation is summarized as Case D in table 4. Given the present cost parameters, a capacity payment just for base and peak plants causes storage to drop completely out of the generation portfolio (i.e., the portfolio that is cost-efficient after capacity payments). To put it differently, such 'discriminating' capacity payments make any investment into the non-qualifying storage technology unprofitable. The resulting plant park without storage is given in table 4; the remaining technologies are able to cover their total costs.

In sum, three of the considered setups (Cases A, C, D) allow market participants to cover their costs and could therefore be sustainably implemented. The calculations illustrated, though, that capacity payments affect the generation mix if payments are not accessible for storage. The total system costs of the three alternatives are compared in figure 2, underlining that a capacity payment-induced change of the generation portfolio also has welfare implications: 'Discriminatory' capacity payments lead to an inferior generation mix, which increases social costs. Consequently, the possibility that capacity mechanisms discriminate storage plants calls for a more detailed analysis, which is provided in the next section.

# 4 Setup of capacity mechanisms

We have shown that the participation of pumped storages in capacity mechanisms affects the total system costs (cf. figure 2). In practice there is typically no direct exclusion of pumped storages from capacity payments. But in some cases the specific design of the capacity mechanism might prevent their participation. Hence, it is required to have a closer look at specific design parameters of capacity mechanisms that might exclude (or at least discriminate) pumped storages.

### 4.1 Design parameters and implications for storage

There are already several good studies covering issues on the design and implications of the implementation of capacity mechanisms (e.g., Battle and Rodilla 2010, Cramton and Ockenfels 2012, Joskow 2006 and Süßenbacher *et al.* 2011). Based on the existing literature and the practical experience that have been made with the implementation of concrete capacity mechanisms, we focus our analysis on those design parameters which are particularly relevant for pumped storages as summarized in figure 3. However, in the following we will first refer to the classification of capacity mechanisms and possible types of the concrete capacity product as these are fundamental design aspects even if those have no specific meaning for pumped storages. After that we will describe each specific parameter mentioned in figure 3 in more detail and explain its implications for pumped storages.

The relevant literature distinguishes often between price-fixed and quantity-fixed capacity mechanisms. Battle and Rodilla (2010, p. 7170) argue that such a classification translates into "determining whether the regulator's main objective has been to ensure a certain quantity of the 'reliability product' or to administratively set a price for the product itself." The purpose of price-based mechanisms is to provide a sufficient financial investment incentive to maintain security of supply on an adequate level. Power producers receive these administrative payments, also well known as 'capacity payments', in addition to their income generated in the spot, intraday and other markets. In contrast, in quantity-based mechanisms the regulator does not fix the price but the installed electricity capacity that has to be provided by market participants. Besides the capacity market with fixed demand-curve, quantity-based mechanisms also include capacity options. Whether a mechanism is price-based or quantity-based, however, has no direct effect for the participation or discrimination of pumped storages for itself.

But the concrete capacity product plays a major role not only for the participation of pumped storages. Defining an adequate product is essential for the success or failure of the whole capacity mechanism. There is a broad range of different products as mentioned for instance by Battle and Rodilla (2010, p. 7177): "fixed or flexible long-term energy contracts, certificates of installed capacity, certificates of available capacity (or available energy), certificates of a certain technology installed capacity, long-term reserves requirements, physical units to be operated by the system operator under certain conditions, energy financial contracts, etc.". As they argue, "there is a certain consensus around the idea that the reliability product should remunerate the capability of producing energy at 'reasonable' prices (...) when the system is suffering a scarcity". But how should scarcity be defined or measured? In a well-functioning market energy prices should reflect the marginal value of production costs and should therefore also indicate scarcity. As energy prices are directly observable they could serve as transparent measure for scarcity (cf. Cramton and Stoft 2007).

The following six parameters are of major importance for pumped storages:

#### 4.1.1 Capacity types

In general, capacity can be provided by new and existing generating units, by demand-side management (DSM) and by transmission capacity. The participation of ***all generating capacities (new and old)*** in the capacity mechanism leads to a trade-off between new investments and the extension of the operating lifetime of existing power plants. In some cases this could lead to more advantageous shifts of the decommissioning of old and slow coal-fired power plants (especially if $CO_2$-prices are low) and to a lack of investments in new faster and more flexible generation technologies like pumped storages or gas turbines which are especially needed in renewable-dominated systems. But the discrimination of existing resources distorts the market. On the other hand existing generation capacities

| | | | | | |
|---|---|---|---|---|---|
| **1. Capacity types** | New gen. capacity | Old gen. capacity | DSM | Transmission capacity | |
| **2. Contract duration** | Hours | Seasons | 1 year | 3 years | 10 years |
| **3. Determination of relevant capacity** | Installed capacity | General availability | Peak availability | Hourly availability | |
| **4. Lag period** | <1 year | 1 year | 3 years | 5 year | 10 years |
| **5. Regional differentiation** | No differentiation | Regional bonus/malus | Regionally restricted | | |
| **6. Market share** | No differentiation | Differentiation | | | |

Figure 3: Capacity mechanism design parameters

have strong incentives to exercise market power. As mentioned by Cramton and Stoft (2007), large suppliers holding significant market shares and own generation capacities with already substantial sunk costs could affect the clearing price by withholding of supply.[6]

Pumped storages cannot only provide 'positive' generation capacity but also 'negative' storage capacity. Especially for new pumped storages it is particularly important to know whether these storage units do not only receive capacity payments for the provision of positive generation capacity but also for the possibility of energy storing. The integration of 'negative capacity' as provided by pumped storages or ***demand-side management*** into a capacity mechanism should in general lead to lower investment needs as there is no longer only one reliability level but a range of reliable investment levels as mentioned by Cramton and Stoft (2005). Consequently capacity prices or payments should decrease due to lower needed capacity levels to secure supply in scarcity hours. Due to less remaining 'needed' generating capacity and potential lower capacity payments the integration of DSM would perhaps lower opportunities for pumped storages to participate. But if DSM can provide enough capacity and further investments in pumped storages are not needed anymore this is of course a desirable (market) result and no discrimination of pumped storages.

The integration of ***transmission capacity*** into a capacity mechanism sets signals to place new generation at adequate places and leads therefore to a tradeoff between network expansion and new generation capacity. In the context of high wind penetration this could lead to a choice between increasing current network capacity for having more export capacity and the investment into new pumped storages for storing wind electricity. But this decision does not discriminate pumped storages in general but is a desirable result of the capacity mechanism.

[6]The basement of capacity prices on the actual capacity and not on the bid capacity could be one possibility to avoid exercise market power as suggested by Cramton and Stoft (2005) as withholding of supply by suppliers has not an increasing effect on the capacity price.

### 4.1.2 Contract duration[7]

The temporal resolution of the capacity mechanism (i.e., the duration of the 'capacity contract') influences significantly the long-term planning-security of potential investors. Generator's risk exposure is higher with shorter contracts. This is especially relevant for investments with long depreciation periods like pumped storages which have depreciation periods of 40–50 years while gas turbines only need 20–25 years for amortization (Konstantin, 2009). A contract duration chosen too short would therefore discriminate pumped storages compared to less capital-intensive technologies.

Given risk-aversion, this may hold off investors. To maintain security of supply sustainably, Süßenbacher *et al.* (2011) argue that it is necessary to provide producers long-term predictable revenues. But as existing power plants already had sunk fixed costs those resources do not need long commitment. Cramton and Stoft (2007) argue that even a short commitment of one year has a reducing effect on a supplier's risk as he can benefit from price distribution. Furthermore the authors point out that multiple-year commitment would complicate the supplier's decision making process as he has to decide to opt out of the market for a year in which he expects lower prices for firm energy as in future.[8] Hence, investors in pumped storages have a strong incentive for long contract duration but at the same time the participation of pumped storages in the capacity mechanism has to be ensured.

### 4.1.3 Determination of relevant capacity[9]

Besides the determination of a required capacity level it has to be clearly defined how the capacity that participates in the mechanism is measured. To choose the ***installed capacity*** seems to be the easiest way to measure supplied capacity. In case of renewables, though, installed generation capacity and energy production can fall apart far. In RES-dominated systems this approach could especially cause problems when scarcity events occur due to the lack of wind. But also for conventional power plants this measurement does not take into account scheduled or forced outages. Furthermore, the use of installed capacity to determine the relevant capacity' is not directly transferable to demand-side management if participating in the mechanism. In most capacity mechanisms the determination of supplied capacity is therefore based on availabilities—in each hour or only in hours of peak demand. Also the determination of general mean values is conceivable.

The conditions for the qualified participation of a power plant at the capacity mechanism are highly relevant especially for pumped storages as those power plants cannot produce constantly. Pumped storages value the water stored in their reservoirs by opportunity costs and produce in peak hours in which demand and prices are high. If capacity payments are linked to ***general availability***, pumped storages cannot participate in such a capacity mechanism and will not receive capacity payments. Currently all of the ICAP markets in the U.S. East Coast measure the supplied capacity by availability: a unit that generates with an availability rate of 90% gets 90% of the ICAP price—a market design that allows almost no market participation of pumped storages. Cramton and Stoft (2005) argue that in such market designs especially those power plants that contribute little to reliability get high capacity payments. Hence, the usage of general availabilities is misleading.

Another way to determine the relevant capacity is to base its calculation on ***peak availability***. The disregard of hours in which security of supply is less pressing allows pumped storages to participate in the market and therefore allows investors to gain their

[7] Cramton and Stoft (2007) refer to this aspect as 'commitment period'.

[8] This applies only in a capacity mechanism in which not only the installed capacity but also the amount of energy produced during periods of scarcity is paid.

[9] Cramton and Stoft (2005) refer to this aspect as 'product measurement'.

investment costs. Different ways to measure availability for new generation capacities which have no historical production time series are possible.

#### 4.1.4 Lag Period

Battle and Rodilla (2010) define the lag period as the "time duration between the moment the commitment of deliverability is signed and the moment the product has to be delivered". As the lag period determines implicitly which new investments may participate in the mechanism this parameter is only (but highly) relevant for the construction of new power plants. Cramton and Stoft (2007), who developed a capacity market design for hydro-dominated Colombia, state that capacity procurement in advance allows new projects to compete before entering the market—and before significant costs are sunk. They argue that a long lag period has several beneficial effects. On the one hand a long lag period increases competition: the higher the lag period, the more (types of) power plants are able to participate; those new resources entering the market set a 'meaningful' capacity price. The authors state that a price set by existing power plants would be wrong due to sunk costs and market power. On the other hand, a long lag period has a dampening effect on boom-bust-cycles which are typical for investments in electricity markets.

Construction times vary greatly among power plant types. While large thermal power plants like lignite or hard coal are characterized by long construction periods, gas turbines and renewables can often be constructed in less than two years. In contrast, building a pumped storage takes 6–12 years due to long authorization periods (because of their impact on the nature) and long construction periods (because of major civil works for dams etc.). If the lag period is chosen too short, the incentive to invest into power plants with long authorization/construction times, such as pumped storages, is low due to the corresponding higher price uncertainty. As stated above, the lag period influences the competitive pressure: In the context of large pumped storages, Battle and Rodilla (2010) argue that a short lag period of e.g., three years with short-term contracts makes the participation of large pumped storages in the capacity mechanism nearly impossible, while long-term contracts combined with a long lag period of seven years 'make life easier' for investments in pumped storages. For hydro-dominated Colombia, Cramton and Stoft (2007) suggest auction periods of 4 years—but give the investors of large hydro projects the opportunity to lock-in the 4-year-ahead auction price (100% or a fraction of its energy delivered) up to seven years ahead. Thus the reduced risk makes investment in long-term capacity projects like pumped storages more attractive to investors.

#### 4.1.5 Regional differentiation

Typically, capacity mechanisms focus primarily on the security of supply. In a system with network congestion, though, a capacity mechanism could also be used to set adequate local investment signals—provided that there is enough liquidity in the market and no potential exercise of market power. If participating capacity types exclude network expansion, local investment signals can be set by a regional differentiation of capacity payments or by the application of different capacity zones. However, the regional differentiation of capacity mechanisms bears the risk of market power and illiquidity if areas are chosen too small. While gas turbines are generally not tied to a specific location, the same does not apply to pumped storages which depend on suitable topographical and geological conditions. In extreme cases a slight change of the borders of capacity zones implies that a specific pumped storage investment is no longer attractive. Besides the regionally restricted capacity markets also regional bonus-malus-systems are conceivable.

| Electricity market | Total generation capacity $(MW)$ | Pumped storage capacity $(MW)$ | As % of total mix | Number of pumped storage plants |
|---|---|---|---|---|
| Ireland[a] | 6,585 | 292 | 4.4 | 1 |
| PJM[b] | 170,481[c] | 5,493 | 3.2 | 5 |
| Spain | 100,560 | 5,347 | 5.3 | 17 |

[a]Republic of Ireland
[b]Including the integration of the ATSI zone
[c]Average offered supply in summer 2011

Table 5: Pumped-storage capacity in selected markets
(source: PJM 2011b, SONI 2011, Red Eléctrica de Espana 2012, Eurelectric 2011)

#### 4.1.6 Market share

While it has nothing to do with the setting of adequate investment incentives for new capacities, regulators might choose to condition payments on the market share of a generator, in order to achieve a less concentrated market and to improve the competitive situation for smaller investors.[10] Especially in countries like Germany, where all pumped storages belong to only a few large companies, such an approach seems to be problematic as smaller investors tend to build rather less capital-intensive generation capacities like gas turbines. However, recently also small utilities consider the new build of storage plants, driven by local authorities to invest into renewable capacities (Steffen 2012).

Many more design parameters exist that are also highly relevant for the design of the 'right' capacity mechanism like the question about auction vs. bilateral contracts and how the capacity product is purchased (centralized vs. bilateral). Closely related to this question is an adequate auction design.[11] However, these make no significant difference for storage plants as compared to other technologies.

### 4.2 International case studies

Building on the theoretical discussion of design parameters, we now analyze the current situation for storage plants in selected electricity markets which have already implemented capacity mechanisms. We focus on Ireland, PJM and Spain as those markets have significant pumped hydro storage capacity as shown in table 5.

To illustrate the differences between the capacity mechanisms, we classify all selected mechanisms along the design parameters described in the previous section (see figure 4). After a short description of the capacity mechanism we highlight specific conditions for storage plants if available and show the implications for pumped storages resulting from the specific capacity mechanism.

#### 4.2.1 Ireland

The Irish Single Electricity Market is organized as mandatory gross pool. Generation units are dispatched centrally. To ensure long-term system reliability, the regulator CNE introduced administrative capacity payments. The calculation of the capacity payments is based on the capacity requirement of the whole system and the annualized fixed costs[12] of the 'cheapest' new peak load power plant, the 'Best New Entry'. The capacity required

[10]For instance, it has been proposed in Germany to limit a power plant support program to plant owners with a German market share in power generation below 5% (cf. Bundesregierung 2011). However, the proposal was not implemented.

[11]See e.g.,Battle and Rodilla (2010) for discussion.

[12]Reduced by the expected revenues from the energy and ancillary service markets

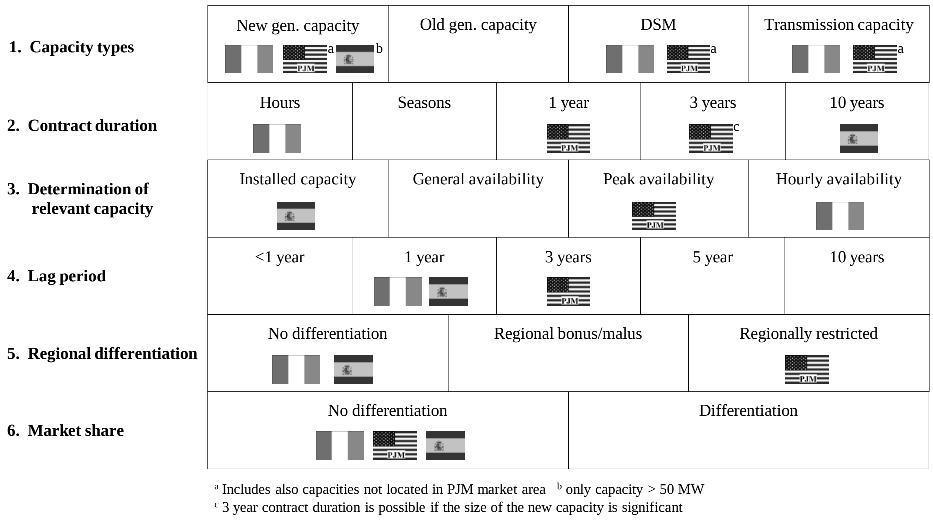


Figure 4: Classification of markets along design parameters

is determined based on forecasted generator availabilities (including both scheduled and forced outages) and a demand forecast for one year. By comparing the resulting loss of load expectation with the applicable security standard for Ireland, the system operator determines the missing or excess amount of generation capacity to meet demand within the security standard. Besides existing and new generation units also demand side management and transmission capacities can receive capacity payments.

To set capacity payments, the annual payment sum is first split into monthly capacity period payments based on weighting factors, which ensure that particularly in months with high load there are also high capacity payments. Those monthly payments are then further divided into three separate components for generators (see figure 5): a fixed, a variable and an ex-post component. The first 30% of the monthly payment are allocated to the trading periods (which are the hours of a month) in the previous year by using fixed capacity payment weighting factors[13]. Another 40% of the monthly capacity payment are variable and is profiled to trading periods by using loss of load probabilities (LOLP). In contrast to the previous described capacity payment types, the remaining 30% of the monthly capacity payment are determined ex-post after the capacity period. Their hourly allocation is therefore based on ex-post LOLP (cf. SEM 2011).

Capacity payments for thermal units are based on hourly availability profiles that are calculated based on the historical forced outage rates over five years. Where such data is not available, mean values for the corresponding generator unit technology are used (e.g., in case of new generation units). The (interim) capacity margin has to be determined to deduct the forecast availability for each trading period h (hour) within the relevant capacity periods. To calculate the capacity margin the forecasted availabilities of the generator units, the interconnectors and wind are summed up before the load forecast value is deducted. The forecast availability of a total generation site then corresponds to the summed forecast availabilities of all units belonging to the generation site. The capacity margins of the generation sites, which are necessary to determine the forecast availabilities, are then determined by the system operator as follows:

[13]Fixed Capacity Payment Weighting Factors = "forecast demand in that trading period relative to the minimum forecast demand in the relevant capacity period" (cf. SEM 2011 )

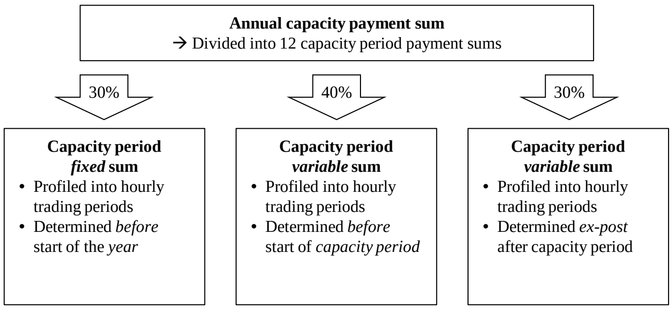


Figure 5: Components of capacity payments in Ireland(source: SEM 2011)

For conventional units[14], the capacity margin is calculated by the usage of historical forced outage factors and temperature correction factors which are, in turn, determined by referring to the historical relationship between temperature and the generator unit's availability.

The capacity margin of energy-limited generator units like pumped storage units is particular considered and not based on any historical data. To determine the capacity margin of a generation site containing pumped storage units, the determination of those trading periods h within each trading day is necessary where the capacity margin is minimal. After that the optimized output from each specific generation site is incrementally increased by *(1 MW)/(number of Trading Periods of Minimum Interim Margin)* until a further increase would lead to a violation of a unit's technical capability and as long as there is sufficient remaining energy at the generation site to do this.[15] After updating the remaining energy for the specific generation site, the interim margin in all trading periods is calculated new and the trading periods where the (interim) capacity margin is minimal are determined again. This procedure is continued as long as there is remaining energy in any generation site containing pumped storage units[16]. See SEM (2012) for a more detailed description of the determination of capacity margins including forced outage rates.

Although the dispatch of pumped storages depends on hourly electricity prices at first sight (as for all generating capacities), the separate estimation of the hourly availabilities of pumped storages in Ireland takes into account that the dispatch of pumped storages further depends on the current fill level—while the dispatch of thermal power plants is normally not limited by the availability of fuel. But due to long investment periods the short lag period poses a relatively high risk for new pumped storages to enter the market. Additionally the uncertainty of the potential capacity income will be increased by the high granularity of the capacity mechanism. But in summary there is no direct or indirect (e.g., by imposing a minimum of availability) exclusion of pumped storages in the Irish capacity mechanism design. It should be emphasized that Ireland only holds one hydro pumped storage and that there is not much further hydropower potential that could be developed (cf. Eurelectric 2011, p. 14).

[14]More precisely: for units other than autonomous generator units, demand site units, wind power units, interconnector units and interconnector residual capacity units (cf. SEM 2012, M.20-M.21

[15]If not, the output is only increased as high as (technically) possible

[16]and energy-limited generator units

#### 4.2.2 PJM

The PJM Interconnection LLC operates as independent system operator at the U.S. East Coast a centrally dispatched wholesale electricity market as well as several further markets including an intraday market, a capacity market and markets for transmission rights and ancillary services. In the delivery year 2007/2008, PJM completely redesigned the capacity market and introduced the Reliability Pricing Model (RPM) to increase performance. According to a load serving entity's share in PJM's peak load, the load serving entities can satisfy their capacity obligation either through own facilities, bilateral contracts, their participation in the RPM capacity market or through the 'FRR Alternative'[17]. Several capacity types can participate in the capacity market: Generation resources, load management resources, energy efficiency resources and qualified transmission upgrades[18]. Beside existing and new resources also resources not located in the PJM area can participate under certain conditions. Planned generation resources can participate if their start date of interconnection service is on or before the start of the delivery year.

PJM's territory is divided into 25 location deliverability areas. For each area, the demand is determined by a Variable Resource Requirement (VRR)[19] curve which is based on the cost of new entry (CONE), a target level of reserve and expected revenue offset from energy- and ancillary services. The RPM defines one occurrence in ten years as reliability requirement. Capacity requirements are determined and a first auction is held three years ahead of the delivery year. To deal with potential changes in PJM's capacity requirement, three further incremental auctions follow to provide additional capacity (20 months, 10 months, and 3 months ahead). With 'new entry pricing' the RPM gives new planned generation resources of significant size a special investment incentive. To increase the security of investment, new generation resources have the possibility to receive the capacity price of the initial auction for the next three years under certain circumstances (cf. PJM 2012).

The reliability value of a generation resource or its unforced capacity[20] depends on two variables: its installed capacity and its equivalent demand forced outage rate (EFORd). The installed capacity is based on the summer net dependable rating and gives the number of megawatts which can be delivered by the unit at the time of PJM's peak load. EFORd gives "the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate" (PJM, 2012, p. 8). For the calculation of EFORd the outage data of the latest five years is used or if not available class average EFORd[21].

Specific rules determine the net capability for pumped storage units. While the determination of their summer net capability is also based on operational data (or if not available on test results), those can be taken at any time during the year (once each delivery year). The same data can be used for the determination of summer and winter net capability. Also the duration of the verification test is shorter (cf. PJM 2010, PJM 2011a, PJM 2012).

PJM's determination of the relevant capacity has no specific impacts on the dispatch or the participation in capacity market for pumped storages. As mentioned in subsection 4.1, long lag periods are advantageous for new pumped storages as their investment periods are long. PJM's locational differentiation sets adequate locational investment signals. When

[17]Load serving entities can choose the option to submit a FRR capacity plan and meet a fixed capacity resource requirement while the capacity resource in the RPM is variable.

[18]From delivery years 2007/2008 through 2011/2012 also 'Interruptible Load for Reliability Resources' could participate.

[19]PJM (2012, p. 162) describes the VRR curve defining "the maximum price for a given level of capacity resource commitment relative to the applicable reliability requirement".

[20]The unforced capacity considers forced outages and forced deratings.

[21]See PJM 2011a for a further description of the determination of EFORd and equations.

building capacity zones this should in general also be done with respect to potential investment in pumped storages at zonal borders as pumped storages investments depend strongly on the location. Allocating a potential pumped storage site to a capacity zone with lower capacity prices could in the worst case lead to a lack of investments in pumped storages.

### 4.2.3 Spain

The Spanish capacity mechanism distinguishes between two types of capacity payments: payments for availability and payments for the setting of investment incentives ('Pagos par capacidad') (cf. Ministerio de industria, turismo y comercio 2007). Although the payments for availability, which differ along generation technologies, are anchored by law they are not implemented in practice yet. In contrast, annual capacity payments for investments are paid to new generation capacities greater than 50 MW for their first ten years of operation[22]. Existing generation capacities do not receive capacity payments. To determine the annual payments, the system operator calculates a reserve margin index ('indice de cobertura') by dividing the total available capacity by the peak demand. The investment incentive is described as a decreasing function of the reserve index (RI) with an optimal value between 1 and 1.1. The annual capacity payment decreases when the RI exceeds a value of 1.1; no capacity payments are paid if the RI is higher than 1.29.

The Spanish capacity mechanism differs from the previously described mechanisms in several points: Capacity payments are only paid to new capacities and all generation technologies receive the same payments per installed megawatt. The determination of available capacity is very simple as it corresponds to the installed capacity of the specific power plant. Special aspects (e.g., no general availability as the hourly production depends on the reservoir fill-level or pumping) are not considered. While the long contract duration is advantageous for investments in pumped storages, the short lag period of one year is disadvantageous. Nevertheless, Spain has currently licensed to build new pumped storages with a total installed pumping capacity of 2,424 MW (cf. Eurelectric 2011).

## 5 General principles and conclusion

The capacity mechanisms implemented in different countries differ considerably, despite the common goal to secure an adequate amount of generation capacity at reasonable costs. The calculations presented in this paper demonstrate that capacity payments are able to prevent power plant investments from falling short of their costs—and at the same time, total system costs increase if storage is excluded from such payments. A number of design parameters determine whether storage plants are able to de facto participate in capacity mechanisms, and different decisions have been made in existing mechanisms. It goes without saying that the specific conditions in each market require somewhat tailored approaches—however, we believe that three general principles can be summed up to ensure the storage-compatibility of capacity mechanisms:

- **Stable, long-term horizon:** While power generation in general is a capital-intensive business, this is especially true for pumped-hydro storage. To stimulate investment into large-scale dam projects, long contract durations for capacity remuneration are required, such that payments are regarded as reliable income stream by investors. Besides long commitment periods, the prolonged permission and construction time of storage plants should be taken into account when lag periods for capacity tenders are decided upon. No least investors have to be able to rely on

[22] They are also payed to existing power plants with significant additional investment activities (e.g., fitting of flue-gas desulfurization on coal plants), cf. Ministerio de industria, turismo y comercio 2007.

the sustainability of capacity mechanism rules—without a stable regulatory environment, storage projects will always loose out against less capital-intensive technologies.

- **Technology-specific availability measurement:** Technology-neutrality is a salient feature of text book case capacity mechanisms: All available contributions to ensure generation adequacy (including demand side management or transmission capacities) should be part of capacity mechanisms in order to achieve an efficient capital allocation. In practice, criteria have to be defined to decide which specific units are allowed to participate, with unit availability being of vital importance. The specific availability indicators and calculation procedures have to take the differences between technologies into account. For pumped-storage systems, consequently, operational restrictions due to reservoir fill levels—at peak load hours—should be the determining factor.
- **Large geographical scope:** By their nature, storage plants are geographically restricted to sites with appropriate conditions in terms of topography and geology. Consequently, the regional structure of capacity mechanisms is much more relevant for storage plants than for thermal units. This not only applies to regional factors within a mechanism, but also to the frontier of the overall system: If power plants are synchronized to a specific power system but located beyond a capacity regime border, this might impact storage plants that cannot be built at the other side of the border, very much in contrast to thermal plants. This should be carefully taken into account in Europe, where several distinct national capacity mechanisms are being discussed while large pumped-hydro potential lies 'next to' these markets in Alpine countries.

In sum, capacity mechanisms are an important way to ensure generation adequacy—chosen by regulators in many markets today and possibly even more widely implemented in the future. The analysis showed that it is possible to include storage plants into those mechanisms, achieving in principal an efficient generation portfolio. Concerning the detailed implementation of capacity mechanisms, we illustrated that several principles have to be met in order to achieve storage-compatibility—they should become an essential feature of future mechanisms in countries where pumped-hydro storage is an option.

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